Prefiled Direct Testimony
Dennis L. Wagner

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
NorthWestern Corporation, d/b/a NorthWestern Energy

For Authority to Increase Electric Utility Rates
in South Dakota

Docket No. EL14-_____

December 19, 2014

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EXHIBITS

None

Witness Information

Q. Please state your name and business address.

A. My name is Dennis Wagner, and my business address is 600 Market Street W, Huron, South Dakota, 57350.

Q. By whom are you employed and in what capacity?

A. I am the Director of South Dakota Production for NorthWestern Energy ("NorthWestern").

Q. Please summarize your educational and employment experiences.

A. I obtained a Bachelor of Science degree in Electrical Engineering from South Dakota State University in 1972. After graduation, I worked for Wagner Electric in Sibley, Iowa, until March 1, 1973. In March 1973, I started working for NorthWestern Public Service Company as an engineer. From 1973 to 1990, I held several different positions in numerous South Dakota towns. In 1990, I was promoted to Manager of Electric Distribution. In 1995, I was promoted to Manager of Electric Operations. I moved into my current role in 2001. I have more than 41 years of experience working for NorthWestern.

Q. Please explain your job responsibilities.

A. My job responsibilities include oversight of the NorthWestern generation resources for South Dakota. I serve as the owner representative on the Engineering and Operating Committees for the three jointly owned steam plants for which Otter Tail Power Company ("OTP" or "Otter Tail") and MidAmerican

Energy Company ("MidAm") are the operators. I oversee all of the internal generation facilities for South Dakota. I am a member on Mid-Continent Area Power Pool ("MAPP") subcommittees and involved in meetings and requests for information that arise for transmission-related issues. I also help track the North American Electric Reliability Corporation ("NERC") requirements in South Dakota related to transmission and generation. I work on and help maintain transmission and other related agreements including all the South Dakota Western Area Power Administration ("WAPA") agreements.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony discusses:

1. The South Dakota generation portfolio;
2. The technical reasons for proceeding with the Big Stone Air Quality Control System ("AQCS") project;
3. The technical reasons for proceeding with the Neal Four ("Neal 4") scrubber/baghouse, Selective Non-Catalytic Reduction ("SNCR"), and Activated Carbon Injection ("ACI") systems;
4. How environmental issues with the Coyote Generating Plant ("Coyote") are being addressed for today and the future;
5. Significant upgrades to the steam plants;
6. Reagent needs for all three coal-fired plants (Big Stone, Neal 4, and Coyote) and future costs after environmental controls are installed on the three plants;
7. Utility-owned generation investments and upgrades.

South Dakota Generation Portfolio

Q. Please describe NorthWestern's electric utility generation portfolio.

A. Currently, NorthWestern relies on approximately 210 MW of coal-fired generating capacity to supply baseload energy plus approximately 150 MW of peaking capacity to provide for peak load requirements, primarily during short periods in the hot summer months. We also purchase summer reserve capacity.

Q. What is the Big Stone Generating Plant?

A. Big Stone is a 475 MW coal-fired plant. It is jointly owned by Otter Tail (53.9%), Montana-Dakota Utilities ("MDU") (22.7%) and NorthWestern (23.4%). It became operational in 1975.

Q. What is the Neal 4 Generating Plant?

A. Neal 4 is a 640 MW coal-fired plant. It is jointly owned by MidAm (40.570%), Interstate (25.695%), NIPCO (4.860%), NorthWestern (8.681%), Corn Belt Power Coop (8.695%), Algona (2.937%), Webster City (2.604%), Spencer (1.215%), Coon Rapids (0.521%), Laurens (0.521%), Bancroft (0.347%), Milford (0.347%), Gruettinger (0.174%), Cedar Falls (2.50%) and Grundy Center (0.333%).

Q. What is the Coyote Generating Plant?

A. Coyote is a 427 MW coal-fired plant at Beulah, North Dakota. It is jointly owned by Otter Tail (35%), MDU (25%), Minnkota Power Cooperative (30%) and NorthWestern (10%).

Q. What are the components of the South Dakota generation portfolio?

A. South Dakota generation assets are as follows:

Location	Baseload/Peaking	% Ownership	MW	Fuel Source	Commercial Date
Big Stone	Baseload	23%	111	Sub-bituminous Coal	1975
Coyote	Baseload	10%	43	Lignite Coal	1981
Neal 4	Baseload	8.68%	56	Sub-bituminous Coal	1979
Aberdeen Unit #1	Peaking	100%	20	Diesel	1978
Aberdeen Unit #2	Peaking	100%	52	Natural Gas/Fuel Oil	2013
Clark	Peaking	100%	3	Diesel	1970
Faulkton	Peaking	100%	3	Diesel	1969
Huron Unit #1	Peaking	100%	15	Natural Gas	1961
Huron Unit #2	Peaking	100%	40	Natural Gas/Fuel Oil	1992
Yankton Unit #1	Peaking	100%	2	Natural Gas/Fuel Oil	1963
Yankton Unit #2	Peaking	100%	2	Diesel	1972
Yankton Unit #3	Peaking	100%	7	Natural Gas/Fuel Oil	1974
Yankton Unit #4	Peaking	100%	2	Diesel	1975
Mobile #2	Peaking	100%	1.75	Diesel	1991
Mobile #3	Peaking	100%	2	Diesel	2008

Q. Does NorthWestern secure any power from renewable sources?

A. Yes. NorthWestern has wind generation in its portfolio. Wind will account for a total of 124.5 MW by the end of 2015. Below is a summary of the Purchased Power Agreements ("PPAs") that NorthWestern has entered into.

- 25 MW Titan I - on line since December 2009;
- 19.5 MW Oak Tree - expected to be on line in December 2014; and
- 80 MW Beethoven LLC - expected to be on line by December 2015.

Q. Does NorthWestern have capacity agreements for upcoming years?

A. Yes. We have a 19 MW contract with Basin Electric Power Cooperative for 2015. We have also entered into a contract with Missouri River Energy Services for 2016, 2017, and 2018 for 30, 30, and 35 MW, respectively.

Q. Please explain the coal supply arrangements for the coal plants and how customers benefit from them.

A. The Coyote Plant located in Beulah, North Dakota is a mine mouth plant that uses lignite coal. The current coal contract with Dakota Westmoreland Corporation ("DWC") expires in 2016. The Coyote owners provided notice to DWC that the current contract would not be renewed, which resulted in a competitive bidding process between DWC and North American Coal Corporation ("NACC"). The owners have entered into a new coal agreement with NACC, which goes through December 31, 2040. The location of the new mine is adjacent to Coyote which eliminates the need for rail transportation.

Big Stone burns sub-bituminous coal from the Powder River Basin. Otter Tail is the plant operator and manages the coal contracts for Big Stone. The coal supply is procured for the next three years, using a combination of fixed price contracts and open market purchases. Coal transportation is provided by Burlington Northern Santa Fe ("BNSF") railroad, and Big Stone is charged a tariff rate for coal deliveries. An emerging issue regarding BNSF coal delivery to Big Stone is a 2013-2014 trend in increased unit train cycle times reportedly caused by increased rail system congestion in the region. As a result, during part of 2013 and much of 2014, the plant was forced to reduce output during off-peak periods in order to maintain a minimum level in the emergency coal stockpile. This reduced output has caused a large increase in energy market purchases at prices significantly higher than plant production cost. This is having a significant impact on customers for purchased power on the open market.

Neal 4 also burns sub-bituminous coal from the Powder River Basin. MidAm is the plant operator and manages the coal contracts for Neal 4. The coal supply is procured through contracts for three- to four-year periods. Coal is also purchased on the open market to cover any additional needs beyond the contract amount. Neal 4 has a train transportation marketing advantage with two available rail delivery options, BNSF and Union Pacific.

Q. Has the U.S. Environmental Protection Agency ("EPA") adopted regulations that impact Big Stone, Coyote, and Neal 4?

A. Yes. All three steam plants are affected by numerous EPA regulations.

<u>Big Stone Air-Quality Control System ("AQCS") Project</u>

Q. Is Big Stone located near a Class 1 area, as defined by the federal Clean Air Act?

A. Big Stone is in Grant County, South Dakota, near Big Stone City. Class 1 areas typically are national parks and wilderness areas. The EPA determined emissions from Big Stone affect the Class 1 area of the Boundary Waters Canoe Area and Voyagers National Park in Minnesota.

Q. What does this mean for Big Stone?

A. In 2005, the EPA adopted the Regional Haze Best Available Retrofit Technology ("BART") Regulations and Guidelines. Among other requirements, BART guidelines require emission controls for specified facilities that began operating between 1962 and 1978 and may emit air pollutants that could reduce visibility in any Class 1 areas across the nation. Consequently, the EPA required the State of South Dakota to submit an implementation plan describing how Big Stone will reduce its emissions in compliance with the BART guidelines.

Q. How did the State of South Dakota follow the EPA guidelines?

A. The South Dakota Board of Minerals and Environment, the permit-issuing authority for the South Dakota Department of Environment and Natural Resources ("SD DENR"), approved rules implementing the South Dakota Regional Haze State Implementation Plan ("SIP") on September 15, 2010. The rules required Big Stone to install a new BART-compliant AQCS to reduce emissions of particulate matter ("PM"), sulfur dioxide ("SO_2"), and nitrogen oxides ("NOx").

Q. What is the timeline to install the new air-quality control system?

A. The rules require the new AQCS to be installed within five years of the EPA's approval of the South Dakota SIP. EPA approved the South Dakota SIP on May 29, 2012. The projected Commercial Date of Operation is October 1, 2015.

Q. Since BART is a case-by-case determination for each unit, what did the SD DENR determine as the best control technology for PM, SO_2, and NOx, based on its technical feasibility, cost, non-air impacts, remaining useful life of the source, and projected reduction of visibility impacts?

A. Based on its extensive technical analysis, the SD DENR made a final determination that the following control technology constitutes BART for Big Stone:

- Selective Catalytic Reduction with Separated Over Fire Air ("SCR", "SOFA", and collectively "SCR/SOFA") for NOx which provides the highest level of control of the control equipment found to be feasible;
- Semi-Dry Flue Gas Desulfurization ("FGD") for SO_2, which provides slightly less than the highest level of SO_2 control among the equipment found to be feasible; and
- Baghouse, for PM, which provides the highest level of control among the equipment found to be feasible.

Q. Does the BART require Big Stone to reduce mercury?

A. While mercury reduction is not required to meet BART rules, the EPA has adopted mercury emissions regulations (Maximum Achievable Control Technology, "MACT") that Big Stone must comply with at approximately the same time the BART controls are installed. The dry scrubber, baghouse, and activated carbon injection will combine to reduce mercury by a target of 90%.

Q. What systems will be installed at Big Stone for emissions control?

A. This installation includes:

- A semi-dry FGD system with a new baghouse that will focus on controlling SO_2 emissions;
- An SCR/SOFA to control NOx emissions;

- An ACI for mercury removal; and
- Balance of plant modifications to include boiler modifications and replacement of the existing baghouse.

Q. What other states are involved in the approval process?

A. Otter Tail requested and received an advance determination of prudence ("ADP") in Minnesota. Both Otter Tail and MDU also requested an ADP in North Dakota and have a settlement pending approval.

Q. Did you request an ADP in South Dakota?

A. South Dakota does not have an ADP statute.

Q. Is installing new AQCS at Big Stone more cost-effective than building a new generation resource that produces fewer emissions?

A. Yes, installing new AQCS at Big Stone helps balance our commitment to cost-effective service and environmental responsibility. Otter Tail analyzed several options, which included environmental upgrades, building new generation, converting Big Stone to natural gas, or retiring the plant. Making environmental upgrades at Big Stone was determined to be the best option.

Q. What is the current cost estimate for the AQCS project?

A. NorthWestern's share will be approximately $103 million.

Neal 4 Scrubber/baghouse, SNCR and ACI Project

Q. What drove the installation of additional environmental controls at Neal 4?

A. The Mercury and Air Toxics Standards ("MATS") Rule (which limits emissions of mercury, acid gases, and other metals) is applicable to Neal 4. To comply with the MATS Rule, several different emission controls are needed. For acid gases, a scrubber was added; for mercury, an ACI system was installed; to address the other metals requirements, a baghouse was installed, and enhanced combustion will be added to minimize organic hazardous pollutants. Enhanced combustion may require more frequent outages from an operation and maintenance ("O&M") perspective once installed. Compliance with MATS is required by April 2015.

Schedule

Milestones	**Date**
RFP Issued	November 2010
Final Permit Application	December 2010
Proposals Submitted	January 2011
Final Permit Issued	May 2011
EPC Contract Executed	May 2011
FGD/BH/SNCR Placed In Service	December 2013
Substantial Completion On NA Scrubber	May 2014
ACI System Placed In Service	November 2014

Q. What are the construction costs for the Neal 4 project?

A. The scrubber was placed in service in 2013, and NorthWestern's share of those costs totaled $21.3 million. The SNCR was placed into service in 2013, and NorthWestern's share will total $1.7 million. The ACI was placed in service on November 13, 2014 with NorthWestern's share totaling approximately $416,000.

Coyote Environmental

Q. What is Coyote doing to address its environmental compliance today?

A. Coyote has numerous environmental compliance activities that are being addressed by the co-owners. Engineering personnel at the plant are continuing to monitor pending regulation requirements and current emissions. Some current concerns regarding regulatory mandates are:

- Coal Ash Residuals Rule Impacts;
- Regional Haze;
- NOx reductions;
- SO_2 reduction;
- 316B-Water intake velocities;
- National Ambient Air Quality Standards ("NAAQS");
- MATS; and
- Carbon Dioxide ("CO_2") rules.

The coal ash residual rule is set to be officially released in December 2014. In 2018, it is expected that the EPA will require the state to formulate a second SIP for the second round of Regional Haze rules. This will include another NOx reduction along with a new SO_2 limit. Coyote will include an informational study of new requirements in the next National Pollutant Discharge Elimination System permit review in March 2018; this should satisfy the requirements for EPA's 316b rule. The proposed NAAQS rule will require the plant to either model or monitor air quality downwind of the plant. This would be an added project and O&M cost. The plant has purchased all of the necessary equipment for the MATS rule and is currently working with test teams for final testing and installation. The CO_2 rule is still being analyzed by the OTP environmental team, but initial review indicated that the proposed North Dakota limit is less damaging than had been projected.

Q. Please provide additional information regarding compliance with the MATS rule.

A. An ACI system is being installed at Coyote during 2014-2015. The MATS rule limits the amount of mercury and other toxic emissions from power plants. The EPA designed the emissions rate based on the type of coal burned; Coyote falls under the lignite subcategory for regulatory purposes.

This project will:

- Allow Coyote to operate and meet the MATS compliance deadline of April 15, 2015;
- Provide Coyote with a reliable Continuous Emissions Mercury Monitor or equipment approved by the EPA to report mercury emissions;
- Evaluate, test, and monitor for other pollutants found in Coyote's exit gas; and
- Continue to provide low-cost energy for customers from a resource that has nearly depreciated.

Q. What is the cost for the ACI?

A. The project is being constructed at a total cost of $2.15 million. NorthWestern's share will be approximately $215,000.

Q. What else is planned at Coyote to help with NOx controls?

A. Installation of Advanced Overfire Air equipment for NOx control is planned by the end of 2016, at an approximate cost of $9 million. NorthWestern's share is $900,000.

Major Investments in Steam Plants

Q. Briefly describe the more significant generation projects since the last South Dakota electric rate filing.

A. Several projects have been completed since the last South Dakota electric utility rate case that have enhanced the reliability of the South Dakota electric generation portfolio. Due to NorthWestern's decisions to implement these projects in a prudent and timely fashion, our customers have enjoyed long-term rate stability as each was accomplished without requiring NorthWestern to seek a rate increase. With careful planning and project oversight, project completion was achieved at what our analysis determined to be the lowest cost. Also, these projects provided necessary improvements to our generation fleet that allowed our low-cost generation resources to continue operating and providing financial benefits to customers as more capital intensive new generation was not needed. In many cases, required improvements to our generation fleet resulted from a need to meet ever escalating federally mandated air quality standards. A summary of these major projects is provided below:

Big Stone

- 2003 – The installation of the Advanced Hybrid Particulate Collector ("AHPC") was part of an earlier EPA environmental control installation at Big Stone. The Big Stone plant owners partnered with the U.S. Department of Energy to jointly fund this project.
- 2005 – Replacement of the High Pressure-Intermediate Pressure turbine increased unit capacity by 5 MW.
- 2007 – The AHPC was replaced by a conventional pulse jet baghouse. This was an improvement to the original AHPC to meet EPA requirements.
- 2008 – The Generator Stator Rewind was necessitated by age, temperature, internal vibration, and deteriorating insulation due to normal wear and tear. This project was done proactively to prevent a major failure.
- 2012 – Installation of the Boiler Radiant Superheater was completed based on concerns related to age. Element alignment issues and age placed the boiler at increased risk for tube failures.
- 2012 – The Distributed Control System was replaced because the existing controls reached the end of their useful life.

Coyote

- 1993 –The replacement of the Secondary Superheat Outlet Pendants was required due to severe "twisting" of the existing tubes. Cracking and failures due to the different metallurgy of the original tubes and erosion of the steel tubes caused the need for replacement.

- 2009 – The High Pressure/Intermediate Pressure Turbine Motor Upgrade was justified on the basis of increased efficiency resulting in additional energy output of 19 MW, and it ensured the long-term reliability of Coyote.

Neal 4

- 2013 – The Reheat Section Replacement project replaced the reheat section on the boiler. Neal 4 experienced multiple outages in the recent past due to reheat tube leaks.
- 2013 – The need for the Low Pressure ("LP") Turbine Replacement was discovered when Neal 4 was removed from service on October 3, 2009 for a five-week scheduled outage. During the inspection process, stress corrosion cracking was detected on both LP rotors.   The LP rotors were replaced for two primary reasons: 1) to remove the rotors and repair the defects found during the fall 2009 outage and 2) to improve MW output and add efficiency improvements by incorporating the LP retrofits to offset and gain back lost output due to the increased auxiliary loading from the scrubber project that was added in the fall of 2013. MidAm is in the process of requesting a 30 MW transmission increase for the additional output from the generator.

Reagent Costs

Q. What are reagents and how do they control emissions?

A. Reagents are chemicals needed to react with emissions from the plants in order to control gases. A description of the main reagents follows:

- Pebble lime is used in the circulating dry scrubber to capture SO_2 emissions.
- Anhydrous ammonia is injected into the SCR, and when passed through the catalyst it reacts with NOx to form N_2 and H_2O vapor.
- Activated carbon is injected into the gas stream and collected on the baghouse bags. As flue gas flows through the bags, the mercury is absorbed by the carbon and captured.
- Calcium bromide further enhances mercury removal by oxidizing elemental mercury, thereby creating a compound that can also be captured in downstream pollution control equipment.

Q. Please describe the reagent costs for Big Stone, Coyote, and Neal 4.

A. Below is a list of expected annual reagent costs for each generation steam plant.

			NWE Typical Cost/Year	
Big Stone:				
	Lime (Scrubber) – SO2 control	-	585,000	
	Anhydrous Ammonia (SCR) – NOx control	-	351,000	
	Activated Carbon Injection (ACI) – Hg control	-	110,214	
	Total		$1,046,214	/year
Neal 4:				
	Lime (scrubber) – SO2 control	-	170,335	
	Activated Carbon Injection (ACI) Hg control	-	37,913	
	Calcium Bromide (CaBr2) (ACI) Hg control)	-	22,490	
	Urea (Ammonia) (SNCR) – NOx control	-	154,526	
	Total		$385,264	
Coyote:				
	Lime (scrubber) – SO2 control	-	145,000	
	Activated Carbon Injection (ACI) – Hg control	-	71,280	
	Total		$216,280	

<u>Utility-Owned Internal Generation</u>

Q. Are there benefits to utility-owned generation?

A. Yes, there are several benefits to utility-owned generation, including the following:

- Utility-owned generation typically provides more price stability for customers over the long term compared to PPAs that have shorter terms than the expected useful life of the generation. By owning and controlling generation, NorthWestern can protect customers from market forces that may drive prices up when the utility is seeking new supply to provide adequate capacity and energy requirements. NorthWestern can reduce energy costs to its customers by providing an economical energy source during peak demand periods when market prices are high.
- Constructing and owning generation provides NorthWestern customers the security of supply and cost benefits of long-lived and depreciating assets. With utility-owned generation, the rate base declines over time while PPAs typically have lower costs at the beginning but increase over the term of the agreements.
- The utility's profits on generation are relative to the authorized return on equity on the capital invested. This return is typically less than that required by a competitive non-regulated entity.
- Owned generation provides operational benefits and will result in a more financially sound utility which benefits customers. These benefits include outage management, dispatch, ramp rates, unit commitments and capital investments for increased efficiency and life extension, and compliance with

new regulations. PPAs are typically non-dispatchable which affects generation costs and could result in backing down lower cost baseload resources to meet hourly loads.

Q. Please describe the major plant capital investments to NorthWestern's internal generation.

A. NorthWestern has made a number of capital investments in its internal generation facilities since its last rate filing. These investments were necessary to continue to provide safe and reliable service to our customers. Major additions include Huron Unit #2, Aberdeen Unit #2, and the diesel engine retrofits.

Q. What is Huron Unit #2?

A. Huron Unit #2 is a dual fuel (gas or oil), jet derivative combustion turbine-driven generator. The foundation and first of the two turbines (Unit #2A), generator, ancillary equipment, and control system were installed in 1991. Phase II of the project added the second turbine (Unit #2B) to the opposite end of the generator and was completed in 1992.

Q. What were the construction costs for Huron Unit #2?

A. The actual cost was $10,904,441, including substation upgrades. The choice to build owned generation versus continuing to make short-term pool purchases was made, in part, to provide added system reliability within the service territory and to help meet operating reserve requirements.

Q. Have there been any major upgrades to Huron Unit #2 since installation?

A. A control system upgrade was installed in 2013 for a cost of $1,245,347.

<u>Aberdeen Generating Station Unit #2</u>

Q. What is Aberdeen Unit #2?

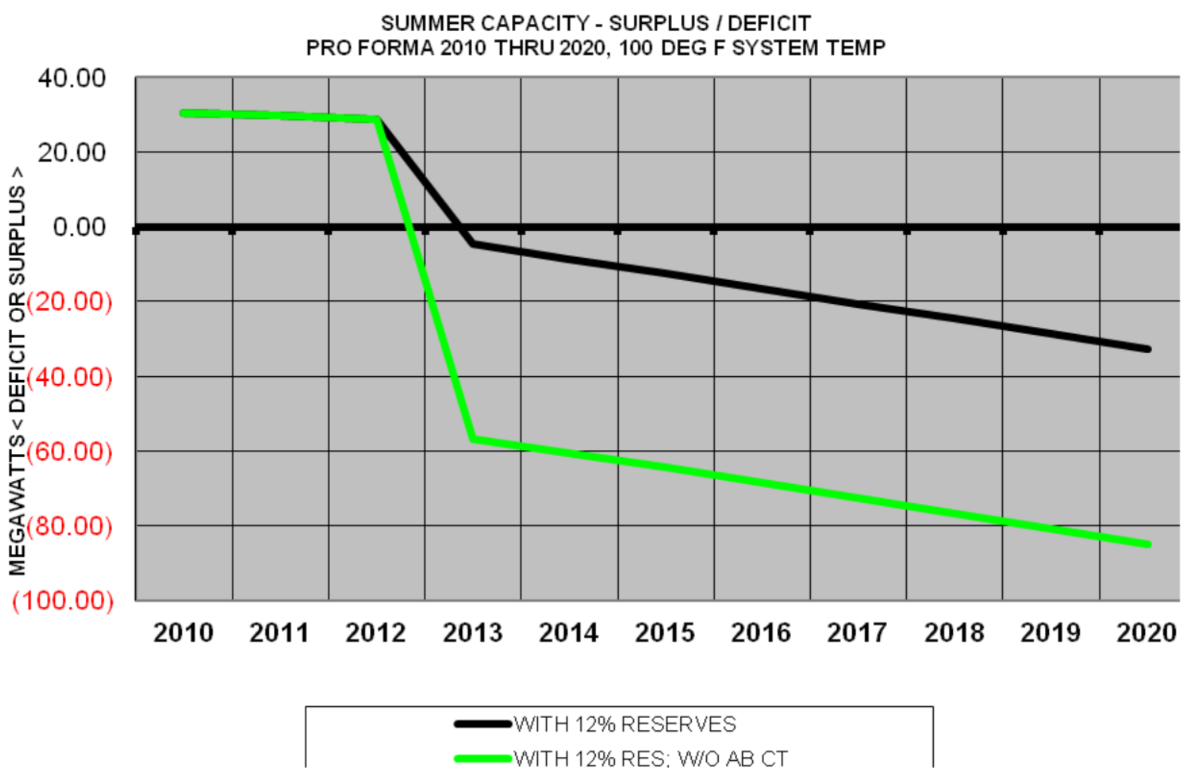
A. Aberdeen Unit #2 is a simple cycle peaking facility located in Aberdeen, South Dakota. The capacity output is rated at 52 MW summer (with inlet fogging) and 60 MW winter.

Q. Why did NorthWestern build Aberdeen Unit #2?

A. NorthWestern identified the need for additional internal generating capacity to meet continuing load growth and the anticipated lack of purchased capacity availability in the foreseeable future. A number of conventional generating projects throughout the region have been delayed or cancelled for a variety of reasons, including environmental, while a large amount of mandated renewable project investment (wind, etc.) has been made with very little actual capacity accreditation.

Furthermore, NorthWestern's requests for firm transmission service for the delivery of generating capacity purchased under a contract for the 2012 summer season were denied by Midwest Independent System Operator ("MISO") due to a lack of available transmission capacity. This problem continued beyond 2012 thereby effectively eliminating the possibility of purchasing capacity from the MISO region. Also, beginning in 2013, NorthWestern forecasted the need for additional capacity during winter periods resulting in an increased need for capacity from four to seven months each year. As a result of that increased need NorthWestern would have experienced increased annual costs for purchasing more capacity. The Aberdeen Unit #2 peaking plant allows NorthWestern to address a portion of the system capacity shortfall and establish a lower, more manageable purchased capacity portfolio. Finally, construction in that time frame allowed NorthWestern and its customers to take advantage of the New Business Refund Program with the State of South Dakota.

The 2010 graph below showed the 2020 demand forecast and the associated deficit in capacity.



Q. What were the tax incentives for timing of construction?

A. NorthWestern was able to receive a refund of sales, use and contractor's excise taxes paid on the construction costs incurred prior to December 31, 2012 by participating in the New Business Facility Refund Program. NorthWestern received a total refund of $765,125.73, which directly benefitted NorthWestern customers as it reduced the overall project cost and resulting rate base.

Q. Why did NorthWestern elect to construct a new generation facility in Aberdeen, South Dakota?

A. NorthWestern selected the Aberdeen location because of the availability of natural gas supply, water supply, and transmission facilities. The location was already owned by NorthWestern so no additional property was purchased.

Q. What was the construction timeline?

A. The major milestones were as follows:

Milestones	**Date**
Board Approval	April 2011
Groundbreaking	October 2011
Natural Gas Pipeline Completed	October 2012
Substation Upgrades Completed	November 2012
First Fire & First Synchronization	December 2012
PWPS Substantial Completion	February 2013
EPC Substantial Completion	March 2013
Commercial Operation Date	April 2013

Q. What were the construction costs for Aberdeen Unit #2?

A. The final cost, including the substation upgrades and the installation of six miles of natural gas pipeline, was approximately $55 million.

Q. When was the project completed?

A. Substantial completion was achieved on March 21, 2013, and the commercial operation date was April 30, 2013.

<u>EPA Mandates for Diesel Engine Retrofit (RICE/NESHAP)</u>

Q. Why did NorthWestern have to comply with EPA mandates for diesel engine retrofit?

A. On February 17, 2010, EPA finalized portions of the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The rule was promulgated into the existing RICE standards located in 40 CFR Part 63, Subpart ZZZZ on March 3, 2010. As a result of this, the EPA mandated that all stationary non-emergency diesel engines must comply with new emission standards in order to control and reduce toxic and hazardous emissions. The new standards applied equally to all existing installed engines, and compliance was required by May 2013. In order to comply, all (stationary, non-emergency) engines in the United States greater than 500 horsepower had to be retrofitted with diesel oxidation catalysts.

Q. What NorthWestern generating units were affected and at what cost?

A. The units affected were Clark, Faulkton, Yankton units #1, #2, #3, and #4. The compliance upgrades cost $1,309,297 and were completed by December 2012.

Q. Does this conclude your testimony?

A. Yes, it does.